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BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

Arizona Corporation Commission
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ENERGY FREEDOM COALITION OF AMERICA'S

OPENING BRIEF

PHASE ONE

October 31, 2016

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TABLE OF AUTHORITIES

Energy Freedom Coalition of America ("EFCA"), through its undersigned counsel, hereby submits its Post-Hearing Brief.

MEMORANDUM OF POINTS AND AUTHORITIES

I. INTRODUCTION AND SUMMARY OF ARGUMENTS.

The Tucson Electric Power Company ("TEP" or the "Company") makes several proposals in this rate proceeding that contradict sound public policy and Commission precedent. Namely, TEP has proposed to: (1) force nearly 4,000 customers onto a new rate class featuring mandatory demand ratchets. Demand ratchets are punitive, volatile, and inappropriate for these customers. TEP has made this proposal before attempting to educate its customers and would leave those customers with no practical means to manage their demand; (2) assess meter fees for new solar Distributed Generation systems ("DG") that would discourage the adoption of solar and that do not reflect that value that DG provides; (3) *not* grandfather commercial DG customers on their current rate design and net energy metering ("NEM") tariff and instead migrate them to a wholly new tariff and seeks to engage in retroactive ratemaking by imposing a grandfathering deadline prior to the issuance of an order in this case; (4) include a DG system from its TEP-owned Residential Solar pilot program ("TORS") in rate base despite the investment clearly being imprudent and TEP failing to meet the prerequisites to allow for the same; and (5) drastically increase its customer charge based on a minimum system analysis.

The Commission may only adopt rates that are "just and reasonable," and it is the Company's burden to provide evidence sufficient to demonstrate that its proposals are just and reasonable. In this proceeding, TEP has failed to meet its burden. All of these proposals are unreasonable and are counter to the interest of TEP customers, and therefore must be denied. As set forth in greater detail below, the proposals would unjustly and unreasonably punish those customers that have already adopted DG and those that are considering doing so in the future. The Commission is required to safeguard the customers from attempts by the utility to adopt new rates, tariffs and other proposals that have not been properly vetted, supported by the evidence, or that are not in customers' best interests. Thus, TEP's proposals identified in this brief should not be adopted or, at a bare minimum, should be deferred until Phase 2 of this docket.

Additionally, the Residential Utility Consumer Office ("RUCO") proposes to have a new RPS Bill Credit Option adopted in Phase 1 of these proceedings. The RPS Bill Credit Option is not appropriate in its current form and it is premature to adopt this proposal in Phase 1 of this proceeding. EFCA therefore requests that the proposal be deferred until Phase 2 of this docket, or in the alternative, if the Commission must adopt it now, EFCA asks that the Commission adopt EFCA's proposed RPS Bill Credit Option proposal outlined herein.

II. DEMAND RATCHETS ARE PUNITIVE AND INAPPROPRIATE; THEREFORE THE MGS RATE CLASS SHOULD NOT BE FORMED AND THE COMMISSION SHOULD CONSIDER AN ALTERNATIVE TO THE RATCHET FOR THE LGS RATE CLASS.

The nature of demand charges makes them volatile, and they subject customers to a greater likelihood of high monthly bills than traditional two-part rates or time-of-use rates. This volatility stems from the fact that demand charges set a large part of a customer's bill based on a short period of time during a billing period, and a demand ratchet mechanism amplifies this problem significantly. Under a standard demand charge, a single instance of high demand can set a large part of the bill for a single month, but under a ratchet, that single instance of high demand can set a large part of the bill for an *entire year*.[1]

The Medium General Service ("MGS") rate class simply should not be formed. TEP's demand ratchet proposal would be particularly difficult for customers to manage because it is not time-of-use-based, but instead based on non-coincident fifteen minute intervals.[2] In total, that equates to *35,040 intervals over the course of a year* that must be managed because any one of them could end up setting the annual demand ratchet.[3] Unfortunately, even those customers who do attempt the daunting task of managing demand during those intervals will be unable to do so effectively, because TEP does not have metering infrastructure in place that is capable of providing instantaneous demand data to the customer in the first place.[4] For seemingly obvious reasons, TEP's witness Craig Jones admitted, no customers have expressed interest in being subjected to a

[1] Jones Tr., Vol XI at. 2587:23-2588:20.
[2] Garrett Tr., Vol X at 2263:9-19.
[3] Garrett Tr. Vol X at 2263:20-2264:2.
[4] Garrett Tr. Vol X at 2263:20-2264:2.

demand ratchet.[5]

The ratchet mechanism TEP has proposed is also bizarre because this type of rate mechanism is not only uncommon, it is particularly uncommon for smaller commercial customers.[6] Small commercial customers are generally in rate classes that not only do not have demand ratchets, but also do not include demand charges in general.[7] Typically, when demand ratchets are used they are applied to rate classes with a small number of very large customers, and each customer's load profile is analyzed prior to designing the ratchet itself.[8] In this case, TEP has not analyzed the load profiles of the potential customers for the proposed MGS class at all.[9]

Further, utilities that pursue demand charges (and ratchets) typically do so as a method of "peak shaving," which means that the charge coincides with the utility's peak demand—when the utility's generation costs are the highest—so the charge sends a price signal to the customer to reduce demand during peak times. TEP's proposal does nothing to reduce peak demand. In fact, TEP witness Craig Jones admitted that under the proposal, an MGS customer could have its demand ratchet set even when TEP's system is experiencing the very lowest overall demand of the year.[10] Such a circumstance would likely result in TEP overcollecting fixed demand-related costs from customers exhibiting the exact behavior the utility is seeking to incentivize—shifting their peak load away from system peak,

A. Demand Ratchets are Poor Public Policy.

In addition to recommending that the Commission reject TEP's proposal to create a new MGS rate class subject to a demand ratchet, EFCA has also proposed that the Commission direct TEP to implement an alternative to its existing demand ratchet on the LGS customer class, consistent with the Commission's direction in the recent UNSE decision.[11] Specifically, EFCA proposes that TEP should be required to reform the existing LGS tariff to assess monthly demand based on the maximum monthly 15-minute interval demand.[12]

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[5] Jones Tr., Vol XII at 2815:22-2816:1.
[6] Garrett Tr., Vol X at 2291:4-16.
[7] Garrett Tr., Vol X at 2291:5-23.
[8] Garrett Tr., Vol X at 2308:16-25.
[9] Garrett Tr., Vol X at 2308:16-25.
[10] Jones Tr., Vol IX at 2024:22-2025:7.
[11] Commission Decision No. 75697 at 86-87:19-28, 1-5.
[12] Direct Testimony at 58:2-4.

The punitive nature of demand ratchets have far-reaching consequences, including discouraging the adoption of energy saving and storage technologies and an unfair impact on seasonal customers.

1. Demand Ratchets Deter Energy-Saving and Storage Technologies.

Demand ratchets deter the adoption of advanced energy saving technologies and, according to RUCO's expert, Mr. Huber, ratchets are wholly incompatible with storage technologies. In this case, as Mr. Jones confirmed,[13] the ratchet would function as a fixed charge – one that may be fixed for a whole year.[14]

In contrast, traditional volumetric rates benefit customers because they give the customer the most control over the bill. Customers recognize that more usage equates to higher bills, so they can reduce usage and experience a corresponding bill savings. Witness Briana Kobor explained, "[t]he volumetric rate is a significant driver and incentive for conservation, both through energy efficiency, demand response, and in addition for distributed generation to offset that volumetric rate."[15] Unfortunately, once a portion of the bill becomes fixed, as TEP has proposed, it is unavoidable. There are no behavioral changes or energy efficiency measures that can be made to address it, so customers have no economic reason to make conservation efforts.

Further, as RUCO witness Lon Huber described, year-round demand ratchets like those proposed by TEP are a deterrent to the adoption of battery storage technology.[16] Inexplicably, TEP has made this proposal even as the Commission explores the adoption of new technologies, including storage.[17] Yet, as Mr. Huber described, "But in terms of like a 24-hour demand charge with a full like ratchet, I mean that would kill storage right out of the gate."[18] "Killing storage" is obviously not an acceptable outcome for the Commission or the public.

Mr. Jones argued that TEP's proposal only discouraged storage if the customer in question

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[13] Jones Tr., Vol IX at 2027:22-2028:1.
[14] Jones Tr., Vol XI at. 2587:23-2588:20.
[15] Kobor Tr., Vol IX at 2135:25-2136:3.
[16] Huber Vol. VII at 1575:12-20.
[17] Commission Docket No. E-00000J-13-0375, In the matter of the Commission's Inquiry into Potential Impacts to the Current Utility Model Resulting from Innovation and Technological Developments in Generation and Delivery of Energy; *see also* Commission Docket No. E-00000J-16-0257, In the matter of the application of Commissioner Tobin's inquiry into reducing system peak demand costs.
[18] Huber Vol VII at 1574:16-18.

reached peak demand outside of the period when storage was utilized,[19] but even he admitted that it may not completely mitigate the problem.[20] Further, he agreed that for customers with a high load factor and steady usage, storage would not help mitigate the effect of the ratchet,[21] and he could not identify any analysis or study that TEP had performed regarding the impact of demand ratchets on energy storage or distributed generation.[22]

Finally, because of the nature of a ratchet, it is a reality that any customer adopting storage (or any other energy or demand reducing technology) must wait a full year for the demand portion of their bill to be impacted by the newly installed storage technology. The idea of making an investment and then having to wait a full year for the ratchet to work its way to allow for any savings (and face the risk of losing a full year of savings for any potential mis-timed discharge) with the new technology is enough to dissuade most customers from adopting new technology when a ratchet is in place.

2. *Demand Ratchets Harm Seasonal Customers.*

Ratchets also harm seasonal customers because customers with seasonal usage can set an annual peak and remain subject to the same demand charge for the next 11 months due to the ratchet.[23] For example, a customer such as a school that operates only during certain times of year could set a demand ratchet based on one of its busy months, and the same demand rate would apply for the remaining 10 months regardless of the school's actual demand during the remainder of the year. Seasonal businesses could be shut down entirely during this time but still would need to pay the same 75% demand rate every single month. TEP witness Jones also acknowledged that applying a demand ratchet would be punitive to seasonal customers.[24]

B. Customers are Unprepared for Demand Ratchets Now and Will Not be Prepared in the Future.

The absence of an education plan for prospective MGS customers is alarming when considering the significance of the rate proposal. TEP is seeking to implement a punitive rate

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[19] Jones Tr., Vol IX at 2041:21-2042:4.
[20] Jones Tr., Vol IX at 2041:21-2042:4.
[21] Jones Tr., Vol IX at 2042:5-8.
[22] Jones Tr., Vol IX at 2038:9-13.
[23] Garrett Direct Testimony at 55:2-14.
[24] Jones Tr., at Vol IX at 2028:19-2029:5.

mechanism before its customers are properly educated on demand ratchets and have any understanding of how they work. As EFCA witness Garrett stated, "[t]he better approach would be to continue with the two-part rates with those customers, leave them in the small general service class. And then if you really believe that they need demand charges, we need to educate them first, not after the fact." [25]

1. TEP's Education Efforts are Not Sufficient or Even in Place.

To be clear, at present there is no education plan in place for the customers TEP would like to place in the new MGS class. Staff witness Howard Solganick recognized that although TEP plans to create an education plan, it has not articulated one to date.[26] The Commission already rejected UNSE's plan to implement mandatory demand rates because it had not engaged in any educational activity first,[27] and like UNSE, TEP has not engaged in any educational efforts either. The limited details that are available about TEP's tentative plans are not encouraging. To begin with, TEP has not even yet clearly identified which customers would be switching into the new rate class, and those customers will not be identified until *after* the resolution of this proceeding.[28] Once TEP selects these customers and only after a nine-month period has elapsed, they will be forced into the MGS class.[29] To make matters worse, if the MGS plan is implemented, future customers would have no transition period at all, because any of TEP's SGS customers who trigger the usage threshold would be forced onto MGS after just three months.[30]

TEP claims to have engaged in customer outreach, but those efforts were limited to answering informal questions about the pending rate case.[31] Craig Jones admitted that not even half the potential customers to be moved to MGS had been contacted.[32] Due to the incomplete and informal nature of these communications, there is no way to know which customers were notified or what customers were told about the new rate class, and because the MGS class participants have not yet been completely identified, TEP obviously has not communicated with the majority of

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[25] Garrett Tr., Vol X at 2261:8-12.
[26] Solganick Tr., Vol X at 2396:2-5.
[27] Commission Decision No. 75697.
[28] Jones Tr., Vol IX at 2019:1-19.
[29] Jones Tr., Vol IX at 2019:1-19.
[30] Jones Tr., Vol XII at 2820:18-25.
[31] Jones Tr., Vol IX at 2021:2-6.
[32] Jones Tr., Vol IX at 2022:10-14.

them. Mr. Jones could not identify how many customers had been contacted, what they had been told, or how often TEP is in communication with these unidentified customers.[33]

TEP also suggests that the nine-month transition period would allow time for communications with customers.[34] That Communication however, will be to tell the customers what happened, not to give them a chance to learn about the proposal and provide thoughtful input in this proceeding. It is unclear how meaningful even this after-the-fact communication will be as TEP expects the cost of this outreach to be "minimal," possibly only $2,000, which would be used to send letters to affected customers.[35] Mr. Jones suggested that other communications were possible but he was uncertain of how they might occur, only that they would not involve additional costs to TEP.[36]

Under TEP's proposal, a customer will be moved onto the MGS rate should that customer exceed 24,000 kWh of usage during a consecutive two-month period no matter if those two months were a mere aberration or not. TEP plans to send a letter to the customer after the first month of usage that suggests to TEP that the customer could reach the 24,000 kWh threshold the following month.[37] This is problematic because by the time the customer is first notified of the MGS class and its potential consequences, that customer will likely be well on their way to reaching the 24,000 kWh limit during the second month. The proposal assumes that these business customers can make rapid changes in usage to avoid getting bumped into MGS, and further that they will be capable of accomplishing that change in usage immediately and within a single billing cycle. For these customers, the receipt of the letter will not only be the first time they are informed of the new MGS rate class and the demand ratchets it includes, but it will also likely inform them that joining MGS is all but inevitable.

Most of these 4,000 potential MGS customers have had no notice of this proposal whatsoever,[38] and therefore have had no opportunity to voice their concerns. These customers deserve better than the casual and after-the-fact approach to education that TEP has described to

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[33] Jones, Tr., Vol IX at 2020:23 – 2022:13.
[34] Jones Tr., Vol IX at 2019:1-19.
[35] Jones Tr., Vol IX at 2019:24-2020:7.
[36] Jones Tr., Vol IX at 2019:24-2020:7.
[37] Jones Tr., Vol XI at 2541:6-16.
[38] Jones Tr., Vol IX at 2022:10-14.

date. The Commission made clear in the UNSE case that until customers are adequately educated on the use of demand rates, such rates will not be approved.[39] There is absolutely no reason to depart from the Commission's precedent set on this issue just a few months ago. In fact, given the punitive nature of the ratchet, it seems there is a stronger case for education before the proposal is even made in this case than in the case of UNSE.

The impacted small business have their own costs and budgets to manage, and they must be afforded the opportunity to become familiar with the demand ratchet proposal and to provide meaningful comment on whether or not it should be adopted. A single letter advising them that they are more than half way to a new rate class featuring mandatory demand ratchets is not fair or appropriate. Similarly, the initial nine-month transition of customers that have never been subject to a demand charge, let alone a ratchet, to the MGS rate, which has an 11-month ratchet, is wholly inadequate. Customers should be afforded no less than 12-months to transition to have time understand a full year of their demand patterns.

2. *TEP's Small Business Customers Cannot and Will Not be Able to Manage Demand Ratchets.*

Under traditional two-part rate designs, customers can control their bills based on their usage, but under a demand rate (or ratchet), the demand portion of the bill is far more difficult to manage because the customer does not know their actual demand until peak demand has already been set.[40] This issue is demonstrated by the fact that TEP does not have demand meters in place.[41] Demand meters are critical because they give the customer the ability to see their current demand, which permits them to control their usage *before* they set peak demand, not after.[42] Staff agreed that instantaneous demand information is best under a demand ratchet.[43] This is because once the peak has been set, a customer has to wait an entire year to do anything about it.

Despite TEP's efforts to share demand information with customers, all of it will still come after the customer's peak demand-setting event. Craig Jones explained that TEP's billing system

[39] Commission Decision No. 75697 at 65:15-18.
[40] Garrett Tr., Vol. X at 2288:8-20.
[41] Garrett Tr., Vol. X at 2256:1-7.
[42] Garrett Tr., Vol. X at 2256:8-16.
[43] Solganick Tr., Vol. X at 2385:18-21.

provides demand data at the end of the month,[44] and that TEP's web portal "would, once in place, give them some availability, but it wouldn't be instantaneous data. It would be prior months kW data, which would already be on their hard bill or electronic if they get it that way."[45] Obviously, learning your peak demand from the paper bill *for* that demand when it arrives is too late for the customer to react, and based on Mr. Jones' description, TEP's web portal will ultimately provide the information no sooner.

To make matters worse, customers will also not have interval data readily available. As discussed above, TEP's demand ratchet is based on fifteen minute intervals.[46] Unfortunately, TEP's web portal, once active, would only provide the highest demand reached during the billing cycle, and the customer's interval data would available upon request once per year, and if the customer would like it more often they would need to pay an additional charge.[47] This is unacceptable because interval data is critical for assessing demand, particularly when the customer has 35,000 intervals to manage. The customer needs to know how their demand is changing throughout these intervals to know how to change behavior. A bill indicating only the peak does not tell the customer anything about the relevant usage before and after the occurrence, whether shifting some usage to a different time would have "shaved" the peak or simply caused the same peak at a different time.

C. The MGS Rate Class Traps Customers and Offers No Clear Way to Escape.

TEP's MGS rate class functions like a trap, and two months of abnormally high usage is all that is required for the trap to be sprung.[48] Current SGS customers have no reason to suspect that they could be subject to a demand ratchet because, as discussed earlier, TEP would notify them only after they are likely to exceed the 24,000 kWh limit. Even more disturbingly, once these customers are caught in the MGS trap and subjected to its demand ratchets, there is no clear way to escape. Simply reducing the demand charge set by the ratchet in the MGS class will require that the customer cut demand by more than 25% of the peak that the customer set when the ratchet

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[44] Jones Tr., Vol. IX at 2031:14-22.
[45] Jones Tr., Vol. IX at 2031:14-22.
[46] Garrett Tr., Vol. X at 2263:9-19.
[47] Jones Tr., Vol. IX 2032:3-14.
[48] Jones Tr., Vol XI at 2541:6-16.

went into effect.[49] Once this is accomplished, the customer will still have to wait eleven months before the ratchet resets to reflect a lower demand peak.[50]

Leaving MGS entirely is another story. TEP has seemingly developed no clear way to leave the class, and Mr. Jones did not articulate any method when asked about the issue other than stating that TEP would consider it during the first year of MGS implementation.[51] Further, Mr. Jones went on to suggest that even if a customer were to maintain demand beneath the 24,000 kWh MGS threshold for an entire year, that customer would not be reverted to SGS automatically, but instead would only be permitted to switch if they then made a request to be moved.[52] TEP will also not contact that customer to notify them that they are eligible to return to SGS,[53] potentially creating a scenario where unknowing customers with usage well below the MGS threshold continue to be subject to a demand ratchet long after they should be. This problem needs to be addressed, because TEP should not have the authority to pick and choose which customers are subject to demand ratchets and which are not.

III. DG ONLY METER FEES ARE UNFAIR AND UNWARRANTED.

TEP would like to impose metering fees on new DG customers in the amount $8.62 per month for residential customers and $9.13 per month for small commercial customers.[54] This is approximately five times the meter fee approved by the Commission in the recent UNS Electric, Inc., ("UNSE") rate case.[55] This fee is to pay for a production meter to measure the output of the DG system. This provides no benefit to the DG customer and is installed solely for the benefit of the utility. As a result, the DG customer should not be bearing the burden of this increased fee.

These fees should not be taken lightly, as they would make a significant impact on the economics of DG. As Mr. Koch described, "[s]o customers who might have average monthly bills in the 500 to 1,000 kilowatt hours a month range who might, corresponding to that usage, who would likely install systems in the 4 to 5 kilowatt range. *Those customers could see as much as a*

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[49] Jones Tr., Vol. IX at 2040:14-17.
[50] Jones Tr., Vol. IX at 2040:9-17.
[51] Jones Tr. Vol. XII at 2818:15-2819:11.
[52] Jones Tr. Vol. XII at 2819:12-21.
[53] Jones Tr. Vol. XII at 2819:12-21.
[54] Jones Tr., Vol. IX at 1977:13-21.
[55] Jones Tr., Vol. IX at 1977:22-1978:9.

year of payback [added] to the economics of their system with the addition of a $6 per month meter fee."[56] These additional charges harm the value proposition of solar and would likely make TEP customers less likely to adopt it.[57] This is particularly true when, as here, the additional charges are fixed and unavoidable.[58]

TEP's production meter fee proposal is also unfair because the charge is for the production meter, which provides no direct benefit to the DG customer. Mr. Koch explained:

> I don't see that there is a compelling reason why an individual customer would be required or would need to have a separate solar meter installed. It seems to me that that separate meter is primarily for the benefit of the company in complying with the renewable portfolio standard. There are certainly other benefits of having that meter in place. But if a customer wasn't required to install that solar meter, they have other means of getting that information and would likely not choose to pay an additional meter fee in order to have that piece of equipment installed.[59]

Indeed, solar customers do not need the production meter to be provided service.[60]

The production meter is used to track compliance with Renewable Energy Standard and Tariff ("REST") requirements[61] and TEP also uses it to calculate its Lost Fixed Cost Recovery mechanism (the "LFCR").[62] Compliance with the REST serves everyone, not only DG customers, but TEP and the community as a whole. The REST rules drive the adoption of clean renewable energy throughout Arizona, and distributed generation is a particularly important component of those rules.[63] DG customers have no duty to install DG whereas it is the Company that has a duty to have DG installed. The production meter is clearly for the benefit of the utility and not needed by the DG customer.

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[56] Koch Tr., Vol. VIII at 1756:12-18. (Emphasis added).
[57] Kobor Tr., Vol. IX at 2127:23-2128:10.
[58] Kobor Tr., Vol. IX at 2127:23-2128:10.
[59] Koch Tr., Vol. VIII at 1756:21-1757:6.
[60] Garrett Tr., Vol. X at 2255:6-8.
[61] Garrett Tr., Vol. X at 2255:6-8.
[62] Huber Tr., Vol. VII at 1473:2.
[63] *See* A.A.C. R14-2-1805.

IV. ALL DG CUSTOMERS, INCLUDING COMMERCIAL DG CUSTOMERS, MUST BE FULLY GRANDFATHERED FOR AT LEAST TWENTY YEARS.

A. The Commission has Repeatedly Stressed the Importance of Full Grandfathering and that should be Upheld Again in this Case.

In the event the Commission adopts any proposal impacting the rates, tariffs and/or export rate of any DG customers (residential or commercial), the customers that submitted an interconnection application prior to the issuance of the final order must be fully grandfathered under the currently-existing rate design and NEM tariff. The grandfathering period should be a minimum of twenty years and should apply to both residential and commercial customers.

It was reiterated in the UNSE docket that the Commission's "default policy" is to fully grandfather all DG customers that submit an interconnection application prior to the issuance of a final decision in a rate case.[64] This policy was endorsed yet again in the recommended order in the pending SSVEC rate case and the recommended order in the Value of Solar docket. In the UNSE rate case, the recommended order specifically acknowledged that grandfathering is an issue arising in virtually every rate case and further, that the order is meant to "provide specific guidance in an effort to be helpful as we move forward through these issues."[65] The recommended order then stated that "[w]e emphasize that this result should be regarded as our default policy."[66]

Additionally, to the extent that the Company is still seeking a "cut-off" date prior to the issuance of a final order in this proceeding, such a cut-off date must be rejected. The Commission has stated time and again, and specifically in the UNSE rate case, that its default policy is not to adopt any date prior to the final order for implementing grandfathering.[67] TEP witness Hutchens acknowledged that the grandfathering in this case should be "consistent" with that ordered in the UNSE rate case.[68] Company witness Tilghman admitted that TEP would not oppose a grandfathering date based on the date of the final order in this proceeding.[69] Therefore, full

[64] Commission Decision No. 75697 at 119:13-17.
[65] *Id.* at 34:24-26, 36:9-11.
[66] *Id.* at 35:1-5.
[67] Commission Decision No. 75697 at 119:13-17 ("In this Decision, we have rejected the Company's proposal to establish a grandfathering date that precedes the date of the Commission order. We emphasize that this result should be regarded as our default policy."); *accord* SSVEC ROO at 34:24 – 36:11.
[68] Hutchens Tr., Vol II at 325:20 – 326:11.
[69] Tilghman Tr., Vol. III at 663:24 – 666:7.

grandfathering of all DG customers should be immediately implemented (as occurred in the UNSE docket).[70]

B. The Company Failed to Justify its Proposal wherein Commercial DG Customers are not Fully Grandfathered Under Current Rate Design and Tariffs.

In this case, TEP proposes that its commercial DG customers not be grandfathered on their current tariff and that they be migrated to a wholly new tariff (*i.e.,* the new SGS, MGS, or LGS class).[71] Specifically, the Company states that it will not extend grandfathering to commercial DG customers because it will allegedly create a "separate class" that will "continue to reap the benefits of their net metering rider."[72] In so arguing, TEP demonstrates a lack of understanding of the purpose of grandfathering.

Grandfathering is a policy meant to protect the rights, investments and interests of customers that invested in DG technology.[73] It is *not* a policy that allows the Company to protect itself from competition. As Vote Solar witness Kobor highlighted:

> It is essential that the Commission safeguard existing NEM customers from drastic and unforeseen rate design changes. TEP's existing NEM customers have made investments in DG systems to serve their family or small business's needs. Many of these customers were encouraged to invest in DG through Commission incentives. By investing in rooftop solar, customers fix a portion of their electricity bills to offset fluctuating electricity rates. Many of these customers have made the investment in rooftop solar as part of a long-term financial plan, perhaps tied to retirement, college, or some other anticipated financial need. By investing in their own energy source, these customers can reduce monthly expenses when their system is paid off, improving savings potential much like paying off a mortgage. Drastic, unforeseen changes to the rate design for these customers have the potential to severely undercut their planned savings.[74]

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[70] Commission Decision No. 75697 at 119:7-24 ("in the upcoming second phase of this proceeding, parties should address how to phase in any changes to the export rate, to banking, to the implementation of demand charges, or to any other significant changes to [NEM] or rate design that would be applicable to new DG customers. This approach would be more consistent with traditional principles of regulatory gradualism.").

[71] Jones Rejoinder Test., TEP Ex. 32 at 28:22 – 29:4.

[72] *Id.*

[73] *See generally* Kobor Tr., Vol. IX at 2105:5-17.

[74] Kobor Direct Test., Vote Solar Ex. 4 at 75:11-22; *accord* Seibel Direct Test., Solon Ex. 4 at 12:13-20.

Commissioner Tobin recognized as much in the Trico rate case when he opined that "I am deeply concerned that nearly all of [the parties in this proceeding] remain unconvinced of the Commission's commitment to *honoring the investments of customers investing in rooftop solar prior to a final decision on an electric company's rates*."[75] (Emphasis added). The purpose of grandfathering to protect DG customers was recognized in the recommended order in the Value of Solar docket as well. The recommended order in that case proposes that the Commission commit itself to ensure that customers that submit an interconnection application prior to the date of a final rate case order be allowed to "continue to utilize currently-implemented rate design and [NEM], and will be subject to currently-existing rules and regulations impacting DG."[76] Thus, TEP fundamentally misunderstands the purpose of grandfathering as it is meant to protect the investments and interests of customers that have already invested in DG prior to the change in rates and tariffs, not extend special treatment or create new classes of customers after the date of the new implementation of rates and tariffs.

Additionally, EFCA is unaware of any policy or decision that supports TEP's position that commercial DG customers are not entitled to the same grandfathering protections as their residential counterparts. Further, as Commissioner Tobin pointed out, it is the onus of the utility to present "substantial evidence" to support its grandfathering proposal and that the "party [seeking] a different outcome on grandfathering or other issues, [ ] they must provide sufficient evidence to warrant such a departure."[77]

The only "evidence" submitted by TEP in support of its proposal to migrate commercial DG customers to a new tariff is that doing so would result in "separate class or treatment for DG customers."[78] As discussed above, this is wholly untrue. The only customers being grandfathered would be those that submitted their interconnection application prior to the final date of the order. No new class is being created or benefit extended. Instead, the currently-existing commercial DG customers would simply continue to operate under the tariffs and rates in place at the time they

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[75] ACC Commission Docket No. E-01461A-15-0363, "Comm'r Tobin Letter" at p. 1 (Oct. 13, 2016).
[76] Value of Solar ROO at 154:3-4.
[77] Commission Decision No. 74884 at 8:8-16.
[78] Jones Rejoinder Test., TEP Ex. 32 at 28:22 – 29:4.

adopted DG and accordingly, will continue to receive the benefits they bargained for when they made such an investment.

Protecting commercial customers' investments in DG is just as important as protecting the investments of residential customers. They too have a right to be free from impermissible retroactive ratemaking such as that proposed by the Company. These protections include ensuring that commercial DG customers will not be migrated to a wholly new class or subjected to demand ratchets.[79] If commercial DG customers are migrated to the newly-proposed classes (and subjected to the new rate designs associated with them), such customers would end up paying "significantly" more upon the transition.[80] When that occurs, the investments made by these commercial customers will be rendered uneconomical and they will be deprived the benefit of their DG systems (just as residential customers would be if they were not grandfathered on the current rates and tariffs). Thus, unless a commercial DG customer opts not to be grandfathered, the grandfathering in this case must encompass commercial customers and prohibit them from being migrated to a new tariff or rate class in the event they are adopted.[81]

V. RUCO'S RPS CREDIT OPTION SHOULD BE DEFERRED TO PHASE 2 OF THIS PROCEEDING BECAUSE THE PLAN IS FLAWED AND INCOMPLETE AS CURRENTLY DESIGNED.

RUCO has presented in Phase 1 of these proceedings its RPS Credit Option proposal. As currently explained by RUCO, the RPS Credit Option would be an alternative to NEM and would not replace it. The RPS Credit Option would pay DG customers a rate for their output that is fixed for 20 years at the time each DG system comes online. RUCO has clarified that this fixed rate could apply either to the DG customer's entire output or just to the power that it exports to the grid.[82] There would be a schedule of declining RPS credits starting at close to the current TEP residential retail rate and then decreasing according to a pre-set series of steps based on installed DG MW capacity.

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[79] Kobor Tr., Vol. IX at 2105:5-17.
[80] Koch Tr., Vol. VIII at 1758:12 – 1759:22.
[81] Kobor Tr., Vol. IX at 2145:8-22.
[82] Huber Surrebuttal Test., RUCO Ex. 11 at 9.

In Decision 75697 in the UNSE rate case, the Commission "on the fly" directed UNSE to offer the RPS Credit Option that RUCO proposed in that case. The option, however, in UNSE is offered only for a short-term, temporary basis until the parties and Commission can "address the long-term feasibility" of this option in the second phase of the UNSE rate case that will address DG issues.[83]

While the Commission adopted the RPS Credit Option as a temporary measure in the UNSE Decision, it should defer consideration of RUCO's RPS Credit Option to Phase 2 of these proceedings. Staff witness Solganick even exclaimed, "procedurally, I think we would be better served waiting for Phase 2" to implement the RPS Credit Option.[84] Upon application of the RPS Credit Option, and adequate study of the rate design, it is clear there are several flaws that need to be addressed before the RPS Credit Option is ready for "prime time." These flaws can be addressed in Phase 2 of these proceedings and there is no urgent need for the rate as currently designed to be adopted in Phase 1 of this matter.

A. The Value of Solar will Inform the Details of the RUCO RPS Credit Option

RUCO has suggested that the average RPS Credit across all of the steps or tranches of capacity should be "the long-term value of solar."[85] RUCO witness Huber derived an estimate of 7.9 c/kWh as the "long-term value of solar."[86] But, stated on cross-examination that the rate was based on a cost-based approach and not the Value of Solar.[87] Huber further explained during the hearing, that the export rate is not set up to pay the value of solar, and is actually set up to pay less than value of solar.[88] It is clear, the rate was not designed to ensure consistent application of the results of the Value of Solar docket. For example, RUCO does not consider capacity-related avoided transmission and distribution costs or the avoided costs of air emissions.[89] Thus, we have only one person's opinion as to the value of solar not informed by any value of solar methodology.

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[83] Decision 75697 in Docket No. E-04204A-15-0142, at Finding 179, p. 142.
[84] Solganick Tr. Vol. X at 2501:16-24.
[85] Huber Surrebuttal Test., RUCO Ex. 11 at 9 ("[t]he basis for each capacity tranche in the RPS Credit Option was formulated to create an average blended rate across all tranches of around 7.7 cents per kWh. This conforms with RUCO's long-term breakeven analysis.").
[86] Huber Direct Test., RUCO Ex. 10 at 37-38.
[87] Huber Tr., Vol. VII at 1474:5-8.
[88] Huber Vol. VII at 1552:14-17.
[89] Beach Supplemental Test., EFCA Ex. 12 at 4-5.

RUCO's direct testimony admits that there is a high degree of uncertainty around its valuation of DG, in part due to a lack of "official Commission position or guidance on this issue."[90] Such guidance is precisely what the Value of Solar decision should provide.

The valuation of DG is the cornerstone of the RPS Credit Option. This value obviously will be a key output of the Commission's adopted Value of Solar methodology. As a result, RUCO's RPS Credit Option is dependent on the Value of Solar Docket and the RPS Credit Option should be considered in Phase 2 of these proceedings to ensure its accuracy. RUCO has not justified preempting the outcome of the Value of Solar Docket when that decision is so close.

B. The RPS Credit Option's Tranches Must be Review in Phase 2 since they are Based on the Value of Solar and Tied to the Economics of DG.

RUCO has proposed under the RPS Credit Option certain tranches of DG generation capacity that, once filled, would automatically lower the applicable credit rate. Mr. Huber admitted he did not know or analyze when each of the tranches would be filled,[91] but upon application it is clear the tranches are set too narrow and directly affect the economics of DG.

Based on the rate of installations in TEP's service territory in 2015, the first five tranches would be fully subscribed within a single year.[92] In fact, if the RPS Credit Option was implemented with the rest of TEP's rates on January 1, 2017, the capacity additions for the first tranche would be expected to be reached within two and a half months.[93] As a result, it appears that the tranches are set too small and the respective rates for each tranche do not comport with principles of gradualism.[94] The DG market will drop quickly to the lowest economic tranche, exhaust the limited available capacity, and go bust.[95] This is similar to the experience in solar markets where incentives have been offered for only a limited amount of capacity. The incentives sell out quickly, and installers must deal with periods of boom and bust. Accordingly, the tranche levels should be reviewed in Phase 2 first to ensure the RPS Credit rate ensures principals of gradualism and allows for economically viable DG.

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[90] Huber Direct Test., RUCO Ex. 10 at 37-38.
[91] Huber Tr., Vol. VII at 1528:16-24.
[92] Kobor Tr., Vol. IX at 2107:1-6.
[93] Kobor Surrebuttal Test., Vote Solar Ex. 5 at 7:14-27.
[94] Kobor Tr., Vol. IX at 2110:23 – 2111:7
[95] Beach Supplemental Test., EFCA Ex. 12 at 8:7-21.

C. The RPS Credit Option is Not Levelized Over 20 years and Immediately Represents a Substantial Reduction in Compensation for DG Customers.

RUCO's proposal uses close to the retail rate as the starting point for the declining schedule of RPS Credits.[96] A bill credit for DG output, however, that is fixed for 20 years at today's retail rate already represents a substantial reduction in compensation for DG customers. This is because, under NEM today, bill savings escalate over time as retail rates increase. For example, if TEP's current residential rate of 11 cents per kWh grows at 2.5% per year, the 20-year levelized retail rate (at a 7.26% discount rate) [97] is 13.3 cents per kWh, which represents the actual 20-year levelized bill savings under NEM.[98] Thus, if the initial step of RUCO's RPS Credit is set at 11 cents per kWh for 20 years, this would represent an immediate 17% reduction in expected compensation for DG customers.[99]

D. Premature Adoption of the RPS Credit Option Based on the Currently Proposed Tranches will Sow Confusion and Add Administrative Expense to TEP.

In UNSE, the Commission has ordered that the RPS Credit Option be reevaluated in Phase 2 of that proceeding.[100] Thus, any adoption of the RPS Credit Option in Phase 1 of this case, would also be reevaluated in Phase 2 of this rate case. The RPS Credit Option should be considered in Phase 2 because the temporary implementation of the tariff sows confusion and adds unnecessary administrative expense.[101]

The core of the RPS Credit Option is the ability of customers to select a 20-year RPS credit rate to apply either to the entirety of their DG output or to their exports to the grid. As a result, even a temporary approval of this Option will create, in essence, a 20-year pilot program that TEP will have to implement and maintain over a 20-year period (if it is successful).[102] This is true even

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[96] Huber Direct Test., RUCO Ex. 10 at 42.
[97] Based on TEP's weighted average cost of capital.
[98] Beach Supplemental Test., EFCA Ex. 12 at 5.
[99] *Id.*
[100] Decision 75697 in Docket No. E-04204A-15-0142, at 142.
[101] Jones Tr., Vol. IX at 2042:17 – 2043:12
[102] Beach Supplemental Test., EFCA Ex. 12 at 5.

if the program is quickly terminated as a result of taking a different direction on crediting DG exports in Phase 2.

Alternatively, if the RPS Credit Option is continued as a result of Phase 2, the tranche structure and rate levels for the credit may be altered in Phase 2.[103] The alteration of the tranches would likely create grandfathering issues with respect to those DG customers who elect the RPS Credit Option before it is revised in Phase 2. These grandfathering issues can be avoided if the RPS Credit Option is evaluated on the same basis and at the same time as all of the other Phase 2 DG proposals.

Further, implementation of the RPS Credit Option would require a substantial effort, including customer education about the new option, website development to provide public daily tracking of the tranches, and the re-design of billing systems. In addition, this expense may be for naught after Phase 2. If Phase 1 of this case concludes in December 2016 or January 2017, the implementation of a temporary RPS Credit Option would require an additional four months (120 days), that is, until April or May 2017, as was provided in the recent UNSE decision.[104] TEP would have to expend significant effort, and unknown but non-trivial costs, to implement a temporary RPS Credit Option program that might have been supplanted by other Commission determinations before it is even implemented. Even RUCO witness Huber, conceded this point.[105] This timing argues in favor of not adopting an RPS Credit Option for TEP on a temporary basis, but instead reviewing this option for TEP in Phase 2 in conjunction with all other proposed rate design and NEM modification proposals.

E. EFCA's Proposed Modifications to RUCO's RPS Credit Option Rate.

Should the Commission still be inclined to implement the RPS Credit Options EFCA has proposed several modifications to address its significant flaws. To start, the RPS Credit Option should be close enough to compensation under NEM to be viewed as a reasonable option for new solar customers, consistent with the rate design principal of gradualism. Therefore, EFCA recommends commencing the RPS Credit Option rate at 95% of the current 20-year levelized TEP

[103] Kobor Tr., Vol. IX at 2106:13-22.

[104] Decision No. 75697, at 116-117 ("In no case should a final Commission determination of the DG issues in this docket take place later than the March 2017 Open Meeting.").

[105] Huber Tr., Vol. VII at 1595-96.

rate, or 12.6 cents per kWh, as the starting credit.[106] The credit would then be reduced by 5% in each successive tier. It is further recommended that the size of each tranche would be 28 MW, the same as recommended by Vote Solar, so the tranches last approximately 1 year.[107] RUCO also appears to agree with this change to the Option to keep the tranches open longer.[108] These fixes to the RPS Credit Option represent a significant improvement over the RUCO proposal. EFCA believes that even if the RPS Credit Option is adopted in Phase 1 with these improvements, it is important to explore and refine the details of this program in Phase 2 in order to ensure its viability and expense.

VI. THE TORS PROGRAM SHOULD NOT BE RATE BASED.

A. The Company's Investment in the TORS Program was Imprudent.

As discussed in greater detail below, the Company was to obtain a prudency review from Staff prior to seeking to rate base the TORS program.[109] Staff did not perform a prudency review,[110] but if it had, the only conclusion it could have reached was that the Company's investment in the TORS program was imprudent.

As explained by Staff witness McGarry, a prudency review is very broad and can be forward or backwards looking.[111] A prudency review is typically performed when utilities make unnecessary investments or make an investment into something that could have been obtained in a less-expensive manner.[112] Although the scope of a prudency review is determined on a case-by-case basis, the types of actions taken in a prudency review include: (1) a determination of whether the utility adopted and followed proper procedures; (2) determination of whether the procedures are reasonable; (3) a review of the exceptions to procedures to ensure they are reasonable and justifiable; (4)determination of whether everything is working as it should; (5) determination of the existence of cost overruns or inefficiencies; and (6) project-specific inquiries.[113] In sum,

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[106] Beach Supplemental Test., EFCA EX. 12 at 9.
[107] Beach Tr., Vol. X at 2314:10 – 2315:8; Kobor Tr., Vol. X at 2229:4-6, 2231:2-10
[108] Huber Tr., Vol. VII at 1624-25.
[109] Commission Decision No. 74884 at 21:12-20.
[110] *See* Abinah Tr., Vol XII at 2856:22 – 2859:21.
[111] McGarry Tr., Vol. IX at 1952:21 – 1953:22; Garrett Tr., Vol. X at 2274:13-22.
[112] McGarry Tr., Vol. IX at 1956:19 – 1957:12.
[113] *Id.* at 1952:21 – 1953:22.

"[p]rudency is a determination of whether or not what was being spent, what actions that management has taken that has resulted in costs that were either inefficient and/or unnecessary."[114]

Although the required prudency review was not conducted, testimony presented in this proceeding unequivocally demonstrates that the investment was not cost-effective and was completely unnecessary. Accordingly, the Commission should simply refuse to permit the rate basing of the imprudent portion of the TORS program proposed in this case.

1. There are Lower-Cost Alternatives to the TORS program.

Staff witness McGarry agreed that a project may be imprudent when "a company [is] making an investment that could have been done in a less expensive manner."[115] The primary justification the Company used in arguing for TORS was that it was needed so that it could obtain DG RECs. RUCO witness Huber explained, however, that TEP obtained DG RECs in the past for 10 cents a watt, but that it costs the Company $2.13 to $2.20 per watt to install DG under the TORS program.[116] TEP could have made offers to existing customers who have retained their RECs for 10 cents a watt or even less and acquired RECs at a much lower price. Thus, the TORS program is significantly more expansive than less expensive alternatives.

2. The TORS program is wholly unnecessary.

Not only is the TORS program not cost-effective, but the Company simply has no need to obtain any additional DG RECs through the TORS program. As stated above, the Company knew from the outset that it could achieve similar ends from investment in utility scale solar or from purchasing DG RECs directly from non-TORS DG customers.[117] Additionally, there is no reason to pursue DG RECs via TORS. To date, the Commission has granted TEP waivers from compliance with the DG carve-out in the REST rules.[118] There is no reason to believe that waivers will not continue to be granted in the future. As Vote Solar witness Kobor explained, "there is sufficient DG on their system installed without incentives in order to meet those REST percentages that are required."[119]

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[114] *Id.* at 1952:8-11.
[115] *Id.* at 1957:8-12.
[116] Huber Tr., Vol. VII at 1581:17 – 1582:23.
[117] *Id.*
[118] Huber Tr., Vol. X at 1579:3-6.
[119] Kobor Tr., Vol. X at 2212:6-12.

As the record shows that there are lower-cost alternatives to the TORS program and that the TORS program itself is unnecessary, the Commission should not only deny the Company's request to rate base the TORS program, but should discontinue the program in its entirety because further investment will continue to be imprudent.

B. The Company Failed to Comply with the Commission's Mandatory Prerequisites for Rate Basing the TORS Program.

The TORS program is a pilot program provided for in a decision issued on December 31, 2014.[120] Notably, the Commission opined that "[t]he Commission's approval of this pilot program should not be viewed as pre-approval for rate making purposes in a future rate case."[121] The order explained Staff's position that "[t]he Commission's *ability to review the prudency of this program* in TEP's *next rate case* provides the Commission *with the ability to protect ratepayer interests…* In essence TEP's proposal is a way of treating company-owned rooftop DG in a manner similar to traditional generation resources, *which are constructed and then put into rate base in future rate proceedings after review by the Commission*."[122] (Emphases added).

Several requirements were then adopted by the Commission that needed to be met *prior* to rate basing the TORS program. This included that a determination of prudency "*will be made during the rate case* in which *TEP requests cost recovery* of this project."[123] (Emphases added). This requirement was especially vital as, at the time the TORS project was implemented, no determination of prudency was made.[124]

The Commission also ordered that TEP "*ensure that the cost of the utility-owned residential distributed generation program is similar to that of third-party programs.* Accordingly, TEP should commit to *cost parity* with current net metering rates, and if rate design is addressed in the future in a way that materially impacts existing net energy metering participants, TEP should evaluate options for existing solar customers, as well as TEP DG customers, to

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[120] Commission Decision No. 74884 at 21:12 – 22:18.
[121] *Id.* at 21:12-20.
[122] *Id.* at 10:4-16.
[123] *Id.* 21:12-20.
[124] *Id.*

minimize any cost parity issues between the two groups and unintended impacts."[125] (Emphases added).

Finally, the Commission required that TEP "include a discussion of the utility-owned residential distributed generation program in its annual REST plan filings . . . beginning with the 2016 REST plan . . . *[t]his discussion shall include a cost/benefit analysis* and shall fully report on all aspects of the program."[126] (Emphasis added).

The Commission's intent is crystal clear that before any aspect of the TORS program was rate based, such action would need to be justified via a prudency review. Further, TEP was to assure that the cost of the TORS DG would be similar to third-party DG and account for changes in rate design impacting existing DG customers and provide a discussion and report of the program, and a cost-benefit analysis. These requirements were put in place specifically to protect the interests of ratepayers. The Company failed to comply with at least three of these requirements and therefore, is prohibited from placing any aspect of the TORS program into its rate base.

1. Staff Failed to Conduct the Mandated Prudency Review.

As explained in greater detail above, Staff had broad discretion as to the form and function of the prudency review. What was *not* permitted by the order was conducting *no* prudency review whatsoever. Multiple witnesses here confirmed that no prudency review of any type was conducted in this proceeding.[127] Staff witness Abinah bluntly stated "no, we did not" when asked whether Staff conducted a prudency review and then explained no prudency review would be conducted until a more substantial amount of TORS systems were asked to be rate based.[128]

2. The Company did not Ensure Cost Parity between its TORS systems and non-TORS systems.

Additionally, in its rate case application, the Company indicates it, "is proposing changes to its rate design to help ensure that all customers pay a more equitable share of the fixed, ongoing costs of providing safe and reliable service. TEP also is proposing to modify its [NEM] tariff"[129]

[125] *Id.* at 22:3-8.
[126] *Id.* at 22:15-18.
[127] McGarry Tr., Vol. IX at 1958:13, 1959:6-10; Solganick Tr. Vol X at 2507:19-24; Tilghman Tr., Vol IV at 990:12-18.
[128] Abinah Tr., Vol XII at 2856:22 – 2859:21.
[129] Commission Docket No. E-01933A-15-0322, "Application," 4:10-16 (Sep. 4, 2015).

Despite requesting changes to rate design that will "materially impact[] existing NEM participants," TEP has not provided any discussion or analysis indicating how it is maintaining cost parity in light of its substantial changes to DG rates and NEM. The bottom line is that without the mandated analysis, it is impossible to know whether there will be cost parity between the two types of DG systems after the conclusion of Phase 2. We have no assurance that after the adoption of the proposed rates that the TORS systems will not be significantly more expensive than non-TORS DG systems in violation of the order.

3. The Company Failed to Provide a Cost-Benefit Analysis to Support its Discussion of the TORS Program.

Finally, although the Company provided a discussion of the TORS program in its REST plan filing, this discussion was not accompanied by the required cost-benefit analysis.[130] In failing to provide this analysis, the parties herein have been deprived of any opportunity to consider costs (such as a potential cost shift caused by TORS systems) and benefits of the TORS program needed to make a rational decision about rate basing it.[131]

It is important to enforce all the prerequisites adopted by the Commission in the order implementing the TORS pilot program. These prerequisites were meant to safeguard the rights and the interests of the ratepayers. The order provides no waiver or deferral language for these prerequisites. Nor does it provide for the Company and Staff to avoid compliance if the request to rate base a portion of the program does not meet some size threshold.

A failure to enforce all the prerequisites would create precedent for the Company and Staff to continue rate basing ever-increasing portions of its TORS program without complying with the safeguards put in place to ensure the viability and fairness of the program.

It is far too late in the proceedings for either Staff or TEP to attempt to cure these defects as the submission of rushed materials would only serve to prejudice the parties hereto. In this case,

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[130] Commission Docket No. E-01933A-15-0239, "Application," pp. 8-10 (July 1, 2015). Although EFCA acknowledges that TEP did provide a discussion and report of the program in its application as required by the order, EFCA does not concede that the provided discussion and report are sufficient to fulfill the requirement. EFCA expressly preserves its right to argue that the substance of the discussion and report provided in this and any future case is inadequate.

[131] *See generally* Kobor Direct Test., Vote Solar Ex. 4 at 24:16-22 (discussing the potential cost shift caused by TORS customers).

it is undisputed that TEP utterly failed to comply with the prerequisites and therefore, cannot have any portion of its TORS program rate based in this proceeding. Thus, if the Commission does not discontinue the TORS program, it should deny the Company's request to rate base the TORS program in this proceeding.

VII. THE BASIC CUSTOMER METHODOLOGY SHOULD BE USED TO CALCULATE THE CUSTOMER CHARGE.

The Company has significantly deviated from the cost of service approach approved in its last rate case for calculating the customer charge. In the past, TEP has used a Basic Customer approach to calculate the customer charge, which means the customer charge is based on an objective, well-defined set of costs that include: (1) metering services; (2) meter reading; (3) customer service; and (4) billing costs.[132] In this case, TEP has changed to the Minimum System Method approach, which adds significantly more costs to the customer charge.

The Minimum System Method is a theoretical method based on the theoretical minimum system it would take to serve the theoretical minimum customer.[133] Under the Minimum System Method, a portion of distribution plant costs (e.g. lines, poles, transformers) are allocated to a customer class based on the number of customers but not based on that customers use of the system.[134] EFCA witness Garret recalculated the customer charge using the Basic Customer Method without these charges and found the basic service charge should only be $8.26 vs. TEP's proposed $15.67.[135] Thus, the Minimum System Method leads to inaccurate and inflated basic service charges.

A. Minimum System Method Does Not Conform to Bonbright's Principals or Provide Accurate Price Signals.

Recovering a large share of distribution system costs through customer charges is neither fair nor based on historic use of the distribution grid. As RUCO witness Huber explains, using the Minimum System Method to derive costs is "equivalent to assessing a per person tax that reflects

[132] Garret Direct Test., EFCA EX. 10 at 36:5-9.
[133] Garret Direct Test., EFCA EX. 10 at 36:10-12.
[134] Huber Direct Test., RUCO Ex. 10 at 16:3-6
[135] Garret Direct Test., EFCA EX. 10 at 36:21-22.

neither the customer's ability to pay nor the benefits received."[136] James Bonbright, the father of modern rate design, also highlighted that the "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible."[137]

In support of using the Minimum System Method, TEP developed an estimate of the proportion of distribution costs in Federal Energy Regulatory Commission Accounts 364-368 that should be classified as customer related.[138] TEP has proposed increasing the costs allocated to its customers from 6% in its last rate case to approximately 13% in this rate case – a 117% increase.[139] TEP has not justified or provided any reasonable rationale for adding these expenses to the basic service charge in this rate case.

TEP witness Overcast, argues that increased diversity in load in the distribution system, justifies the charges.[140] Overcast fails to acknowledge or state that there is increased diversity in load for any common facility that is shared among multiple users.[141] This is true for even local branch lines feeding individual customers.[142] Thus there is nothing individually customer related among these common distribution charges identified by Overcast. Overcast presents no clear rationale or boundary for when and where certain facilities that are common to many users should be considered customer-related costs versus demand or energy-related costs.[143]

Overcast also fails to demonstrate how the use of common distribution charges in the basic service follows the principle of cost-causation since the Minimum System Method does not only recover the incremental costs that arise from serving individual customers.[144] The averaging of customer charges also violates the "matching principle" as there would undoubtedly be variations in the exact cost of the service drop and customer meter to serve individual customers.[145] By contrast, the Basic Customer Method limits the customer charge to a narrower, definable set of

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136 Huber Direct Test., RUCO Ex. 10 at 16:16-18.
137 Garret Direct Test., EFCA Ex. 9 at 36:8-12, n.42.
138 Kobor Direct Test, Vote Solar Ex. 4 at 71:10-25
139 Baatz Direct Test, SWEEP and WRA Ex. 1 at 10.
140 Overcast Direct Test., TEP EX. at 13:20.
141 Huber Surrebuttal Test. RUCO Ex. 11 at 15:6-13.
142 Huber Surrebuttal Test. RUCO Ex. 11 at 15:6-13.
143 Huber Surrebuttal Test. RUCO Ex. 11 at 14-24.
144 Huber Direct Test., RUCO EX. 10 at 15:10-20
145 Huber Surrebuttal Test. RUCO Ex. 11 at 25-26.

costs that can be tied to the customer with a greater degree of certainty and precision while safeguarding against inflated customer charges. [146]

It appears through the use of the Minimum System Method the Company will likely propose increasingly higher fixed charges by adding additional distribution charges into the customer charge. This is a door that should not be opened. Indeed, several public utility commissions have similarly rejected the Minimum System Method because it overinflates customer charges including Utah, Illinois, Maryland, Texas, Arkansas, Colorado and Washington.[147] According to SWEEP/WRA witness Baatz, a study commissioned by the National Association of Regulatory Utility Commissioners found that the Basic Customer Method is the common method used in over 30 states.[148] Even Overcast's lone example of Connecticut supporting the Minimum System Method was found to be false, as Connecticut actually has a statute in place that specifically bars using that method.[149]

Finally, the ever increasing use of putting grid distribution costs in the basic customer charge is a classic slippery slope. Theoretically all customers could be argued to commonly use the system, so every common facility all the way up to the power plant could be labeled as a customer cost.[150] Such an outcome is neither fair nor balanced and TEP's proposal to use the Minimum System Method should be denied in its entirety.

B. The Minimum System Method Reduces Customers' Incentives to Conserve Energy.

Under the Company's proposal, a significantly greater share of each customer's bill will be collected through a higher basic service charge based on the minimum system method. If the Company's proposal were adopted, each customer would have a much smaller portion of their bill over which he or she has control. For example, under the proposed rates, customer will be unable to control 20% of their total bill compared with 11.5% under the current rates.[151] Thus, under the Company's proposal there would be a significant increase in the portion of customers' bills over,

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[146] Garret Direct Test., EFCA EX. 10 at 36:5-9.
[147] Huber Direct Test, RUCO Ex. 10, 17, n.12; Huber Surrebuttal Test., RUCO Ex. 11 at 17, nn.3-5.
[148] Baatz Direct Test, SWEEP/WRA Ex. 1 at 10, n.2
[149] Huber Tr., Vol VII at 1466:4-8.
[150] Huber Surrebuttal Test., RUCO Ex. 11 at 15:16-16:2.
[151] Huber Direct Test., RUCO Ex. 10 at 20:16-20.

which they will be unable to manage through energy conservation. Additionally, by proposing to recover more of the Company's fixed costs through a higher fixed rate, the resulting volumetric rate included in the Company's proposal is lower. A lower volumetric rate, however, dampens the price signal customers receive, further reducing the incentive for customers to conserve energy.[152]

VIII. CONCLUSION.

For the reasons discussed in this brief, EFCA requests that the following actions be taken in this proceeding:

(1) TEP's proposal to form the new commercial MGS rate class should be rejected.

(2) The Company's proposal to impose demand ratchets on its MGS customers should be rejected. TEP must be ordered to successfully implement and complete a substantive educational plan before proposing adoption of any demand ratchets in the future.

(3) TEP should be ordered to eliminate its existing LGS demand ratchet.

(4) In the event that the Commission adopts the new MGS rate and/or demand ratchets for commercial customers, it must grandfather all commercial DG customers that submitted an interconnection application prior to the issuance of a final order in this proceeding on their current rates, tariffs, and rate designs.

(5) TEP's proposal to charge DG customers for the installation of a production meter should be rejected in its entirety.

(6) The Commission should reject the Company's proposal to rate base its TORS program or any portion thereof and deem the TORS program imprudent and discontinue any additional implementation of the program.

(7) If the Commission does not discontinue the TORS program, it should reject the Company's proposal to rate base its TORS program or any portion thereof for failing to comply with the prerequisites for rate basing the program and/or for being an imprudent investment.

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[152] Huber Direct Test., RUCO Ex. 10 at 21:1-5.

(8) The proposed increase to the residential customer charge utilizing the minimum system method should be rejected and a new charge in the amount of or around $8.26 as calculated using the basic customer method should be adopted.

(9) A decision on the adoption of RUCO's proposed RPS Bill Credit Option should be deferred until Phase 2 in order to avoid creating issues relating to grandfathering and to allow the Commission and parties hereto the opportunity to consider the outcome of the Value of Solar docket.

(10) In the event the Commission opts to approve an RPS Bill Credit Option in Phase 1 of this proceeding, it should adopt the proposed changes presented by EFCA or Vote Solar.

(11) To the extent that any proposal impacting the rates, tariffs, or rate designs currently applicable to DG customers are adopted, all DG customers (both commercial and residential) that submitted an interconnection application prior to the issuance of a final order in this proceeding must be fully grandfathered on the current NEM tariff and their current rate design for a period of at least twenty years.

RESPECTFULLY SUBMITTED this 31st day of October, 2016.

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Original and 13 copies filed on
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I hereby certify that I have this day served a copy of the foregoing document on all parties of record in this proceeding by regular or electronic mail to:

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